OPG

EB-2016-0152

OEB Staff Compendium

Panel 2Aii

information on any changes to the index of two years ago. As with 2nd Generation IR, there will be no explicit adjustments for return on equity or debt costs.

2.4 Productivity and Stretch Factors

Under a price cap mechanism, the allowed rate of change in the price of regulated services is restricted by the growth in an inflation factor minus an X-factor. Generally, the X-factor has two main components: the productivity factor and the stretch factor.

The productivity component of the X-factor is intended to be the external benchmark which all firms are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.

The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that firms are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by company and depend on the efficiency of a given company at the outset of the IR plan. Stretch factors are generally lower for firms that are relatively more efficient.

Issues and Options Raised in Consultations

PEG's report entitled "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario" (the "PEG IR Report") makes specific recommendations for the productivity and stretch factor components of the X-factor and provides a discussion of relevant IR precedents.

In brief, PEG recommended in the PEG IR Report that for Ontario distributors, the X-factor be comprised of: (1) an industry TFP-based component reflecting TFP growth potential estimated using U.S. data; and (2) an efficiency benchmark-based stretch factor based on Ontario data.

mandated by the CNSC or that could otherwise increase safety or environmental risks or the risk of non-compliance with legislated requirements.

The proposed stretch reductions are in addition to efficiencies and performance improvements within the company's business planning processes. OPG continually strives to improve the company's performance and operational efficiency where it can do so safely within operational requirements (e.g., CNSC requirements) and without affecting reliability. Through the gap-based nuclear business planning process described in Ex. F2-1-1, OPG develops initiatives to meet these goals. The performance initiatives incorporated in the business planning process and the corresponding performance and operational efficiency improvements are reflected in the forecast expenditures in this application.

As noted above, the stretch factor applies to approximately 75% of OPG's nuclear OM&A. While OPG does not expect to find material efficiencies in the remaining 25% during the term of this application, it will seek to improve performance and reduce costs where it can responsibly do so.

3.2.1. Derivation of Proposed Stretch Factor

OPG proposes a stretch factor of 0.3%, which is based on the methodology used by the OEB to set electricity distribution rates. Under the RRFE, distributors may be subject to a range of stretch factors from 0% to 0.6%,[34] based on their benchmark performance. OPG has adopted the OEB's range in its proposed ratemaking frameworks for both hydroelectric and nuclear generating facilities.

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[34] Under the RRFE, electricity distributors are assigned to one of five performance cohorts based on their forecast costs relative to econometrically predicted benchmark costs. Based on their determined performance cohort, distributors are assigned a stretch factor of 0%, 0.15%, 0.3%, 0.45% or 0.6%..

As set out in the 2015 Nuclear Benchmarking Report, Darlington's Total Generating Cost per MWh performs in the top quartile, and the Pickering facility is in the fourth quartile.[35] OPG used a production-weighted average to determine a combined stretch factor value of just below 0.3%. Chart 9 illustrates the derivation of OPG's proposed stretch factor, based on the most recent OEB-approved nuclear production forecast.

Chart 9 – Derivation of Nuclear Stretch Factor

Input	Value
OEB-approved 2015 Darlington production (TWh)	25.0
OEB-approved 2015 Pickering production (TWh)	21.6
Darlington stretch factor (based on benchmark performance)	0.0%
Pickering stretch factor (based on benchmark performance)	0.6%
Production-weighted average stretch factor	0.3%

OPG has reduced the requested payment amounts by 0.3 per cent of the company's nuclear Base OM&A and allocated corporate support OM&A beginning in 2018. The amounts shown in Ex. F2-2-1 reflect the full forecast revenue requirement. The stretch reduction is applied when determining the company's payment amounts in Ex. I1-3-1.

In order to emulate the effect of the stretch-factor in the OEB's 4GIRM price-cap framework, OPG has calculated annual stretch reductions such that prior years' reductions are maintained (i.e., reductions to revenue requirement made in 2018 are carried forward to subsequent

[35] OPG has used its OEB-approved total generation cost benchmarking performance to determine where the company's nuclear division should fall on the OEB's range of stretch factors. OPG's 2015 Nuclear Benchmarking Report is filed at Ex. F2-1-1, Attachment 1. The Total Generating Cost benchmarking results are on p. 65.

other cost drivers. This variable estimates that cost should rise by 1.7% per year for reasons not identified by other variables in the model.

4. Benchmarking Results and Updated Stretch Factors

Table 3 (A) presents a summary of benchmarking results for each distributor from 2011-2015. The first three columns contain the annual results for 2012, 2013, and 2014. The average of these three results was used to determine the 2016 stretch factor published in July 2015. The 2015 cost performance results are then presented and a new three-year average of the 2013-2015 cost performance is calculated to determine the 2017 stretch factor. This updated average cost performance is used to assign updated stretch factors to distributors.

The last column presents the difference between the updated average cost performance and that calculated previously. All but six distributors had average cost performance that changed by less than 5%.

The average actual cost performance of the 71 LDC benchmarked was better than predicted by the model by 1.14% in 2011, 0.06% in 2013, 2.51% in 2014, and 2.61% in 2015. It was worse than predicted by 0.67% in 2012. Part of the 2012 performance can be explained by the impact of previously deferred accounting smart meter OM&A expenses included in measured cost. Average 2013-2015 cost performance for the industry improved by 1.09% relative to 2012-2014 levels. This improvement in average performance is due to the overall cost performance improvement in 2015 and given that the 2012 inferior performance is excluded from the new three-year average.

As part of its procedures to improve data quality, OEB staff invited distributors to submit corrections to previously provided data. OEB Staff reviewed and considered the data corrections requests and PEG evaluated the data provided in response to the data request to identify any warranted corrections. The revised data were incorporated into the databases and the 2014 results were recalculated to demonstrate the impact. Table 3 (B) shows the impact of LDC data revisions on 2014 cost performance.

Updated stretch factors are assigned based on a three-year average of actual less predicted cost over the 2013-2015 period. As discussed in the Board Report, distributors that averaged

25% or more below cost received the lowest stretch factor of 0%. Those that averaged between 10% and 25% below cost received a stretch factor of 0.15%. Those within 10% of predicted cost received a stretch factor of 0.30%. Those distributors that had cost in excess of 10% to 25% of that predicted received a stretch factor of 0.45%. Any distributors that had cost in excess of 25% were assigned the highest stretch factor of 0.60%.

Table 4 presents a summary of the current and previous years' cost performance results and corresponding stretch factors. The assigned stretch factor for almost every company was not affected by the 2015 update. A total of ten companies have been assigned different stretch factors. Of these, seven now have lower stretch factors and three have higher stretch factors. Table 5 presents the updated stretch factor assignments in the format of Appendix D of the Board report.

Many more distributors changed stretch factors with this update than have in the past. One reason for the greater number of changes is that the relatively poor measured performance in 2012 has been dropped from the new three-year average (i.e., 2013-2015). A second reason is that LDCs on average have maintained the performance gains achieved in 2014 and in some cases improved upon that in 2015. The last reason is that many of the LDCs that changed stretch factors were quite close to the threshold criteria for changing cohorts as a result of the previous update and only modest changes in performance were required.

5. Validation and Other Supporting Documents

As part of their reporting requirements, distributors are asked to validate the numbers contained in their scorecard. Many distributors had difficulty understanding and validating the results contained in previous benchmarking reports. As part of its process improvement initiative, OEB Staff commissioned additional work to make these calculations more accessible and transparent. In collaboration with a committee of industry members, the working papers and documentation were upgraded with the purpose of making them a tool to assist LDCs in validating their benchmarking results. The result was an enhanced benchmarking Spreadsheet

Table 5

Stretch Factor Assignments by Group

Group I	Group II	Group III		Group IV	Group V
Stretch Factor = 0%	Stretch Factor = 0.15%	Stretch Factor = 0.30%		Stretch Factor = 0.45%	Stretch Factor = 0.60%
Cooperative Hydro Embrun Inc.	**Collus Power Corporation**	**Atikokan Hydro Inc.**	**Milton Hydro Distribution Inc.**	Canadian Niagara Power Inc.	Algoma Power Inc.
E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.	Bluewater Power Distribution Corporation	Niagara Peninsula Energy Inc.	Chapleau Public Utilities Corporation	Hydro One Networks Inc.
Halton Hills Hydro Inc.	Entegrus Powerlines	Brantford Power Inc.	Niagara-On-The-Lake Hydro Inc.	Enwin Utilities Ltd.	Toronto Hydro-Electric System Limited
Hydro Hawkesbury Inc.	Espanola Regional Hydro Distribution Corporation	Brant County Power Inc.	North Bay Hydro Distribution Limited	Festival Hydro Inc.	West Coast Huron Energy Inc.
Northern Ontario Wires Inc.	Essex Powerlines Corporation	Burlington Hydro Inc.	**Oakville Hydro Electricity Distribution Inc.**	**Hydro Ottawa Limited**	
Wasaga Distribution Inc.	Grimsby Power Incorporated	Cambridge And North Dumfries Hydro Inc.	Orangeville Hydro Limited	Midland Power Utility Corporation	
	Haldimand County Hydro Inc.	Centre Wellington Hydro Ltd.	Orillia Power Distribution Corporation	Peterborough Distribution Incorporated	
	Hearst Power Distribution Company Limited	**Greater Sudbury Hydro Inc.**	Ottawa River Power Corporation	PUC Distribution Inc.	
	Kitchener	Erie Thames Powerlines Corporation	Powerstream Inc.	Renfrew Hydro Inc.	
	Lakefront Utilities Inc.	Fort Frances Power Corporation	Rideau St. Lawrence Distribution Inc.	Wellington North Power Inc.	
	London Hydro Inc.	Guelph Hydro Electric Systems Inc.	Sioux Lookout Hydro Inc.	**Woodstock Hydro Services Inc.**	
		Horizon Utilities Corporation	St. Thomas Energy Inc.		
	Newmarket	Hydro 2000 Inc.	**Tillsonburg Hydro Inc.**		
	Oshawa PUC Networks Inc.	Hydro One Brampton Networks Inc.	Thunder Bay Hydro Electricity Distribution Inc.		
	Welland Hydro-Electric System Corp.	Innisfil Hydro Distribution Systems Limited	Veridian Connections Inc.		
		Kenora Hydro Electric Corporation Ltd.	Waterloo North Hydro Inc.		
		Kingston Hydro Corporation	Westario Power Inc.		
		Lakeland Power Distribution Ltd.	Whitby Hydro Electric Corporation		

As set out in the 2015 Nuclear Benchmarking Report, Darlington's Total Generating Cost per MWh performs in the top quartile, and the Pickering facility is in the fourth quartile.[35] OPG used a production-weighted average to determine a combined stretch factor value of just below 0.3%. Chart 9 illustrates the derivation of OPG's proposed stretch factor, based on the most recent OEB-approved nuclear production forecast.

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In order to emulate the effect of the stretch-factor in the OEB's 4GIRM price-cap framework, OPG has calculated annual stretch reductions such that prior years' reductions are maintained (i.e., reductions to revenue requirement made in 2018 are carried forward to subsequent

[35] OPG has used its OEB-approved total generation cost benchmarking performance to determine where the company's nuclear division should fall on the OEB's range of stretch factors. OPG's 2015 Nuclear Benchmarking Report is filed at Ex. F2-1-1, Attachment 1. The Total Generating Cost benchmarking results are on p. 65.

Total Generating Cost* ($/MWh)	Forecast 2016	Business Plan 2017	2018	2019	Projection 2020	2021
Enterprise	[redacted]					
Nuclear	63.2	75.6	74.6	74.5	77.1	77.3
Hydroelectric	[redacted]					

* Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

The business plan builds on efficiencies achieved to date, with a focus on pursuing further opportunities for cost effectiveness improvement across the generating business units and support services. In 2016, OPG adopted Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness, in addition to TGC per MWh metrics for each of the Nuclear and Hydroelectric operations. Enterprise-wide targets for TGC per MWh range from approximately [redacted] over the 2017-2021 period. The [redacted] in the TGC over the planning period reflects [redacted] the Darlington refurbishment outages, as well as [redacted] large hydroelectric project [redacted] the Sir Adam Beck I GS power canal liner rehabilitation. The TGC targets are adjusted for hydroelectric generation losses due to surplus baseload generation conditions.

A prominent feature of the OEB's incentive regulation framework is to encourage productivity savings. In particular, for the hydroelectric business, OPG's application requests regulated rates that reflect annual increases of less than inflation. For the nuclear business, OPG's application includes a stretch factor that reduces recoverable OM&A expenses below planned levels. This will challenge OPG to find additional cost savings within its operations, beyond those already reflected in planned cost levels. In order to improve profitability, OPG must identify and implement such additional efficiency improvements starting as early as 2017, with cost savings growing over time.

Benchmarking studies have indicated that OPG has reduced the gap to the average nuclear staffing benchmark from 17% in 2011 to 4% in 2014. With further sustained headcount reductions since 2014, OPG is confident that its current and planned nuclear staffing levels are at the benchmark level. OPG also benchmarks the costs of the Pickering and Darlington stations against other nuclear stations. On a per unit, basis, OPG's all-in operating and capital expenditures for the stations continue to be amongst the lowest in the industry. OPG's nuclear stations will continue to target strong reliability performance, including a top-quartile forced loss rate performance of 1.0% for the Darlington station and a 5.0% forced loss rate for the Pickering station consistent with planned investment levels, for the 2017-2019 period. The operational targets and associated initiatives for the Nuclear business unit are found in Appendix 4, with OPG's Nuclear strategic planning framework included in Appendix 5.

The hydroelectric stations continue to exhibit strong cost effectiveness performance, with regulated fleet operating costs, excluding Gross Revenue Charge (GRC) payable to the Province, benchmarking in the second quartile relative to peers. Operating targets for 2017-2019 include strong fleet-wide hydroelectric availability factors averaging [redacted] per year. The operational targets and associated initiatives for the Renewable Generation & Power Marketing (RG&PM) business unit are found in Appendix 6.

The operational targets and associated initiatives for OPG's centre-led Business and Administrative Services organization, which is focused on providing cost effective information technology, supply chain and real estate services in support of business priorities, are found in Appendix 7.

Production

Total planned OPG production ranges from [redacted] per year over the 2017-2019 period, [redacted] forecast in 2016 and [redacted] in 2021. This reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016, including a partial overlap starting in 2021 between the second and third unit refurbishments.

The following other main factors affect the variability in the planned nuclear production over the period:

- Incremental planned outage days at the Pickering station to enable continued operations in line with the business case approved by the Board in November 2015;
- Single Fuel Channel Replacement outage work at the Pickering station in 2019 and at the Darlington station in 2017 and 2020;

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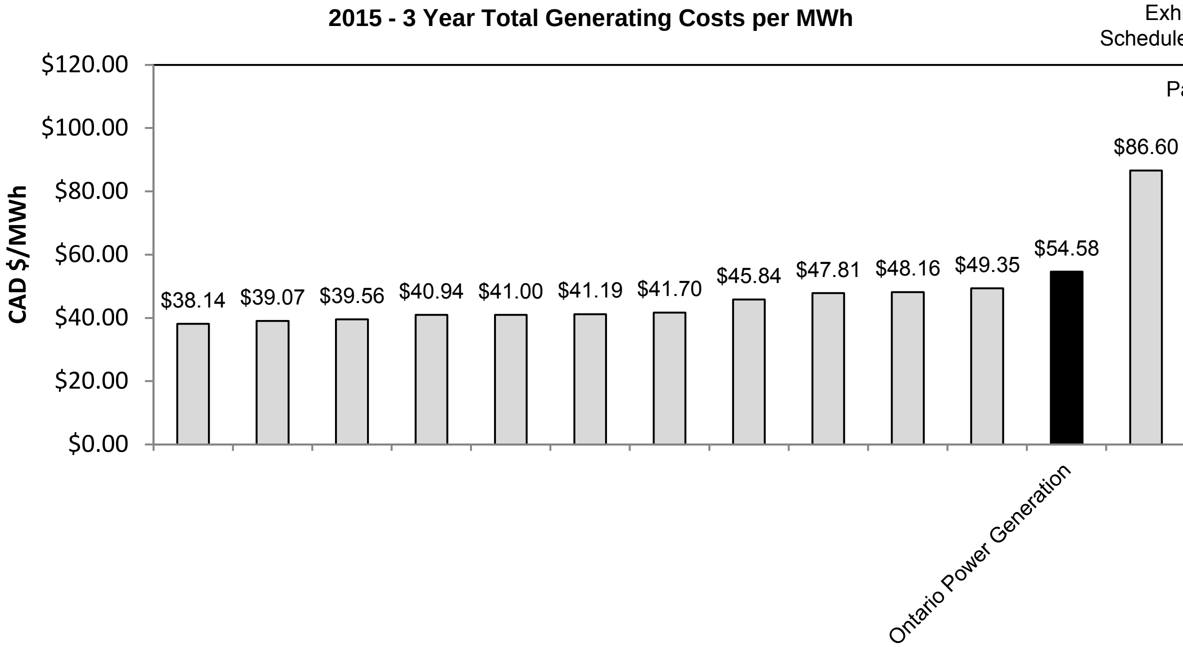

*OPG plant values of 3-year rolling average TGC per MWh are shown below:

Unit	2015 3-Year TGC
Darlington	$44.38/MWh
Pickering	$67.36/MWh

Table 5: Three-Year Total Generating Cost per MWh Rankings

	2010	2011	2012	2013	2014	2015
	9	7	4	1	1	1
	4	4	5	4	4	2
	1	2	2	6	5	3
	3	1	1	2	2	4
	2	3	3	3	3	5
	10	8	7	7	6	6
	NA	NA	NA	11	7	7
	14	13	14	14	12	8
	5	5	6	5	8	9
	11	11	11	9	9	10
	7	9	9	10	11	11
Ontario Power Generation	12	12	10	8	10	12
	13	14	13	13	13	13
	8	10	12	12	NA	NA
	6	6	8	NA	NA	NA

Note: Two operators have been removed due to acquisitions by the other operators in the panel (reason for 14 ranked operators in 2010 vs. 13 in 2015).

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Total Generating Cost is comprised of: (a) Non-Fuel Operating Costs, plus (b) Fuel Costs, plus (c) Capital Costs. Table 6 below shows the relative contribution of these cost components to Total Generating Cost and compares OPG's costs to those of all EUCG operators.

Table 6: EUCG Indicator Results Summary (Operator Level)

EUCG Indicator Results Summary	OPG Average	EUCG Major Operators*		Units
		Median	Best Quartile	
Value for Money Performance				
3-Yr. Non-Fuel Operating Costs per MWh	$ 43.53	$ 24.64	$ 23.63	CAD $/MWh
3-Yr. Fuel Costs per MWh	$ 5.42	$ 9.04	$ 8.04	CAD $/MWh
3-Yr. Capital Costs per MWh	$ 5.63	$ 7.38	$ 6.60	CAD $/MWh
3-Yr. Total Generating Costs per MWh	$ 54.58	$ 41.70	$ 40.94	CAD $/MWh

*See Table 8 in the appendix for list of operators included.

Notes: This summary contains the average of all plant results per operator. The calculation of the EUCG 3-Yr Total Generating Costs per MWh median and best quartiles has been modified. Previously, 3-Yr TGC/MWh was derived by summing the quartile rankings of the three sub-components of TGC/MWh. The revised approach derives the 3-Yr TGC/MWh by reference to actual quartile performance.

Filed: 2016-05-27
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Exhibit F2-1-1
Attachment 1
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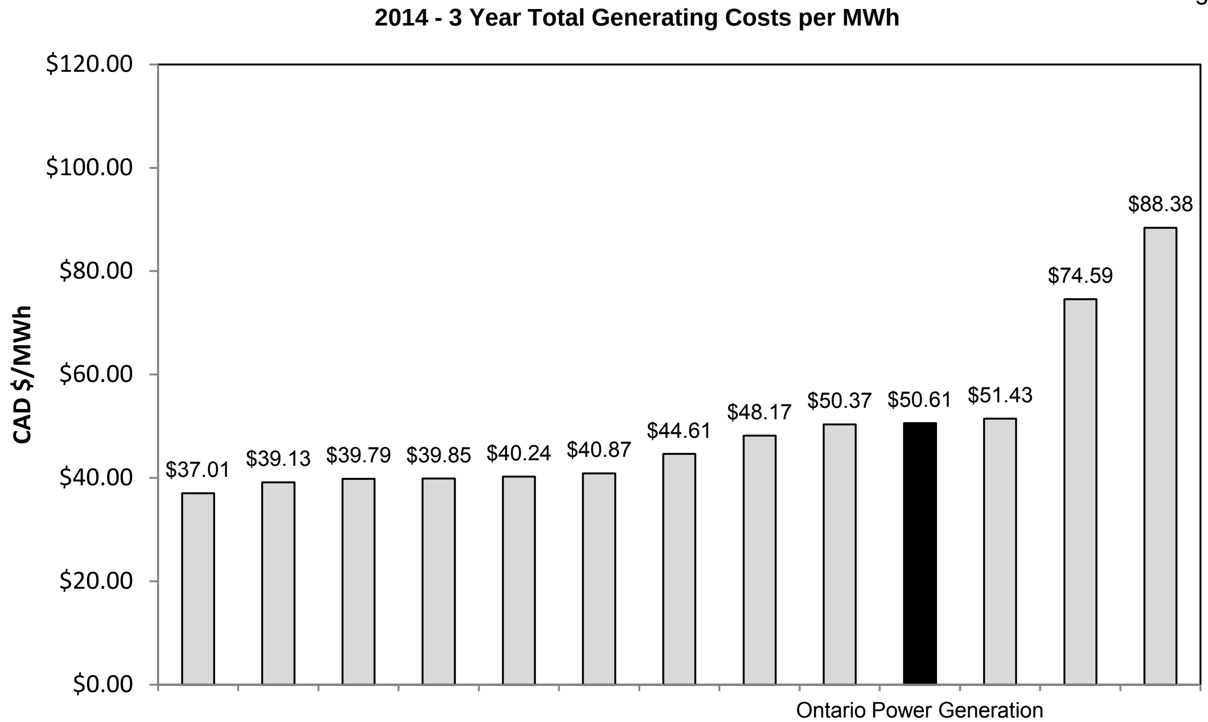

*OPG plant values of 3-year rolling average TGC per MWh are shown below:

Unit	2014 3-Year TGC
Darlington	$37.73/MWh
Pickering	$67.93/MWh

Table 5: Three-Year Total Generating Cost per MWh Rankings

	2009	2010	2011	2012	2013	2014
	11	9	7	4	1	1
	5	3	1	1	2	2
	2	2	3	3	3	3
	3	4	4	5	4	4
	1	1	2	2	6	5
	10	10	8	7	7	6
	NA	NA	NA	NA	11	7
	4	5	5	6	5	8
	8	11	11	11	9	9
Ontario Power Generation	12	12	12	10	8	10
	7	7	9	9	10	11
	14	14	13	14	14	12
	13	13	14	13	13	13
	9	8	10	12	12	NA
	6	6	6	8	NA	NA

Note: Two operators have been removed due to acquisitions by other operators in the panel (reason for 14 ranked operators in 2009 to 2013 vs.13 in 2014):

Total Generating Cost is comprised of: (a) Non-Fuel Operating Costs, plus (b) Fuel Costs, plus (c) Capital Costs. Table 6 below shows the relative contribution of these cost components to Total Generating Cost and compares OPG's costs to those of all EUCG operators.

Table 6: EUCG Indicator Results Summary (Operator Level)

EUCG Indicator Results Summary	OPG Average	EUCG Major Operators*		Units
		Median	Best Quartile	
Value for Money Performance				
3-Yr. Non-Fuel Operating Costs per MWh	$ 40.65	$ 25.60	$ 23.40	CAD $/MWh
3-Yr. Fuel Costs per MWh	$ 5.39	$ 9.03	$ 7.93	CAD $/MWh
3-Yr. Capital Costs per MWh	$ 4.56	$ 7.89	$ 5.78	CAD $/MWh
3-Yr. Total Generating Costs per MWh	$ 50.61	$ 42.53	$ 37.12	CAD $/MWh

*See Table 8 in the appendix for list of operators included.

Notes: This summary contains the average of all plant results per operator. Numbers may not add due to rounding.

MEMORANDUM OF AGREEMENT

BETWEEN
Her Majesty the Queen in right of Ontario, as represented by the Minister of Energy (the "Shareholder" or “Minister”)
And
Ontario Power Generation, Inc. ("OPG")

5.8 The OPG Board Chair shall report to the Minister annually on the effectiveness of this MOA. Such report shall be provided to the Minister in writing within 90 days after the end of each fiscal period.

5.9 OPG shall provide to the Minister quarterly status updates on its response to the recommendations set out in the Auditor General's 2013 Report.

6 PERFORMANCE EXPECTATIONS

6.1 Operational Expectations

6.1.1 OPG shall operate its generating assets safely, efficiently and cost-effectively, and in accordance with all applicable safety and environmental regulations and standards.

6.1.2 OPG shall pursue cost-effective and efficient operational improvements that maintain the reliability of operations, the safety and security of OPG assets, employees and the public.

6.1.3 OPG shall undertake periodic benchmarking appropriate for its operations and type of assets, including as part of its submissions to the OEB.

6.1.4 OPG shall operate its Ontario based portfolio of generation assets in a manner that contributes to Ontario's and Canada's environmental objectives.

6.1.5 OPG shall ensure that a system is in place for the creation, collection, maintenance, and disposal of records in accordance with corporate policy, guidelines and best practices.

6.1.6 OPG shall make information targeted to the general public available in French where it meets a need to do so.

a. Recognizing that OPG's direct interaction with the public is often limited to regional or host community communications or broader public safety, OPG shall make information available in French only if reasonable in the circumstances.

b. For greater clarity, OPG shall provide the following services and products in French: advertising, news releases and educational materials where it meets a need to do so. As well, public safety communications, annual financial reports and educational materials will be provided in French and French speaking spokespeople will be made available as required for public and media interaction. French language products will be listed under a specific heading on the OPG web site.

c. This list shall be reviewed by OPG annually.

6.1.7 OPG shall support the province of Ontario in implementing its policy of putting conservation first by pursuing energy efficiency improvements in its operations where

Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")

And

Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B Governance Framework

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

   - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
   - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
   - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
   - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. Generation Performance and Investment Plans

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of Finance. These performance targets will be benchmarked against the

performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. Financial Framework

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. Communication and Reporting

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. Review of this Agreement

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:	On Behalf of the Shareholder:
Original signed by:	Original signed by:
Jake Epp Chairman Board of Directors	Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy, Dwight Duncan

MR. MILLAR: Okay. And that's -- but inherent in benchmarking is it's not so much the absolutes that matter, it's your relative performance to your peers. And that is what your shareholder asked you to do?

MS. SWAMI: They did ask us to benchmark. And as you know, we have talked a lot about the setting of the targets. We look to set our targets to make those improvements.

But as I have said, the other utilities are also doing a similar process and they are also driving their performance.

So yes, while we are benchmarking, the benchmark is constantly changing as well.

MR. MILLAR: And the shareholder in the memorandum of agreement didn't draw any distinction between Pickering and Darlington; is that fair?

MS. SWAMI: That's correct.

MR. MILLAR: It just said OPG's nuclear operations?

MS. SWAMI: As far as benchmarking, yes.

MR. MILLAR: So I asked you a question and I am not sure I got an answer. My question is: Are you satisfied with your level of performance so far?

MS. SWAMI: We are never satisfied with our level of performance. We are always striving to make improvements.

And would I like to see us move up the relative ranking? Of course. OPG is always interested in trying to make our performance better, and that's why we have targeted improvement programs, which we have talked about in the evidence and I won't go through them here.

But clearly we would like to see better performance from our plants.

MR. MILLAR: Is it fair to say -- and I guess I am not quite sure where 10 out of 14 is, but for the three key metrics, at least up to 2011 and for at least two out of three up to 2012, you would be in the bottom quartile overall?

MS. CARMICHAEL: No -- well, if you look at our benchmarking report for Darlington, we are in top quartile TGC --

MR. MILLAR: I am talking overall.

MS. CARMICHAEL: From a major operator perspective comparison, I would say that on a quartile basis it does appear to be that.

I would also like to just give you a little bit of information. I know that relative to the rankings, we appear to not be improving, but if you look at the absolute numbers of our -- for our company, for OPG nuclear we have shown improvement in those three areas. So in -- for our unit capability factor from 2008, we were at 77.4 percent and in 2012 we were at 82.9 percent.

This just is substantiating Ms. Swami's statement that we are improving but the industry also is improving, so it's a relative issue.

In terms of total generating cost, in 2008 on an operator level, we were at $60.34, and we have improved in 2012 to $46.92.

complete.[30] The proposed nuclear Custom IR framework attempts to strike such a balance, reflecting the fact that OPG's capital and operating costs will vary significantly with the refurbishment of the Darlington facility and the extension of operations at Pickering, but also implementing benchmark-driven stretch reductions in aspects of the company's nuclear operations where it is reasonable to do so.

The proposed nuclear Custom IR framework reflects the OEB's conclusions. It is based on five individual nuclear revenue requirements, but includes incremental stretch reductions that are sustained, year-over-year, creating a meaningful incentive to continuously improve performance and cost efficiency during the IR period.

3.2. Stretch Factor Proposal

As described above, any form of incentive regulation proposed for OPG's nuclear assets must be appropriate in the context of the significant programs planned for the company's nuclear facilities during the IR period. OPG proposes a benchmark-based stretch factor that will provide a meaningful performance incentive during the term of this application.

OPG recognizes the OEB's expectation that an IR mechanism should incent performance improvements, and should be based on measures that are external to the company's forecasts. To achieve this, OPG proposes to apply a benchmark-based stretch factor to revenue requirement attributable to the company's nuclear Base OM&A and allocated corporate support services OM&A.[31] This reduction is in addition to the performance improvement initiatives reflected in the company's gap-based nuclear business planning process. The proposed stretch reduction has the effect of reducing revenue requirement for these two significant categories of expenditures below forecast.

[30] OEB Consultation Report, p. 9.
[31] Descriptions of nuclear Base OM&A and corporate support services are available at Ex. F2-2-1 and Ex. F3-1-1, respectively.

Table 1
Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	OM&A:									
	Nuclear Operations OM&A									
1	**Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	**Project OM&A**	105.7	101.9	115.2	98.2	113.7	109.1	100.1	100.2	86.8
3	**Outage OM&A**	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5
4	**Subtotal Nuclear Operations OM&A**	1,510.8	1,450.3	1,588.5	1,621.3	1,718.9	1,728.9	1,763.8	1,759.4	1,671.6
5	**Darlington Refurbishment OM&A**	6.3	6.3	1.6	1.3	41.5	13.8	3.5	48.4	19.7
6	**Darlington New Nuclear OM&A**[1]	25.6	1.5	1.3	1.2	1.2	1.2	1.2	1.3	1.3
7	**Allocation of Corporate Costs**	428.4	416.2	418.8	442.3	448.9	437.2	442.7	445.0	454.1
8	**Allocation of Centrally Held and Other Costs**[2]	413.5	416.9	461.0	331.9	80.2	118.2	108.3	91.1	81.3
9	**Asset Service Fee**	22.7	23.3	32.9	28.4	27.9	27.9	28.3	22.9	20.7
10	**Subtotal Other OM&A**	896.5	864.1	915.5	805.0	599.7	598.3	584.1	608.6	577.1
11	**Total OM&A**	2,407.3	2,314.5	2,504.0	2,426.3	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
12	**Nuclear Fuel Costs**	244.7	254.8	244.3	264.8	219.9	222.0	233.1	228.2	212.7
	Other Operating Cost Items:									
13	**Depreciation and Amortization**	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
14	**Income Tax**	(76.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
15	**Property Tax**	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
16	**Total Operating Costs**	2,859.3	2,806.2	3,027.8	2,979.4	2,881.6	2,924.4	2,961.9	3,187.9	2,868.2

Notes:

1 Nuclear Operations expenditures to maintain the Nuclear New Build option. In addition there are allocated corporate costs (included in line 7) for Nuclear New Build of $0.8M in 2016, $1.1M in 2017, $0.2M in 2018, $0.5M in 2019, $0.5M in 2020 and $0.5M in 2021.

2 Comprises centrally-held costs from Ex. F4-4-1 Table 3 and amounts of approximately $1M-$6M per year for machine dynamics and performance testing services provided by Hydro Thermal Operations in support of Nuclear Operations.

mandated by the CNSC or that could otherwise increase safety or environmental risks or the risk of non-compliance with legislated requirements.

The proposed stretch reductions are in addition to efficiencies and performance improvements within the company's business planning processes. OPG continually strives to improve the company's performance and operational efficiency where it can do so safely within operational requirements (e.g., CNSC requirements) and without affecting reliability. Through the gap-based nuclear business planning process described in Ex. F2-1-1, OPG develops initiatives to meet these goals. The performance initiatives incorporated in the business planning process and the corresponding performance and operational efficiency improvements are reflected in the forecast expenditures in this application.

As noted above, the stretch factor applies to approximately 75% of OPG's nuclear OM&A. While OPG does not expect to find material efficiencies in the remaining 25% during the term of this application, it will seek to improve performance and reduce costs where it can responsibly do so.

3.2.1. Derivation of Proposed Stretch Factor

OPG proposes a stretch factor of 0.3%, which is based on the methodology used by the OEB to set electricity distribution rates. Under the RRFE, distributors may be subject to a range of stretch factors from 0% to 0.6%,[34] based on their benchmark performance. OPG has adopted the OEB's range in its proposed ratemaking frameworks for both hydroelectric and nuclear generating facilities.

[34] Under the RRFE, electricity distributors are assigned to one of five performance cohorts based on their forecast costs relative to econometrically predicted benchmark costs. Based on their determined performance cohort, distributors are assigned a stretch factor of 0%, 0.15%, 0.3%, 0.45% or 0.6%..

The OEB considers the asset price inflation value used by PEG to be more appropriate. The 2.0% annual growth rate is more closely aligned to the value used by the OEB as the annual inflation factor.

Similarities between the Experts

There were also areas where the experts agreed. While they disagreed on the rate of increase, both experts did agree that Toronto Hydro's costs are increasing at a faster pace than the US comparators'.

b) Application of the Stretch Factor to Capital

Some parties argued that a stretch factor should be applied to capital as well as OM&A costs. They pointed out that the OEB has always applied stretch factors to total costs rather than just OM&A costs. Others did not favour this approach, and submitted that the capital budget should be reduced or it should be linked to performance metrics instead.

Toronto Hydro argued that the stretch factor should not be applied to capital (the C factor) as productivity is sufficiently embedded in Toronto Hydro's capital plan and the rate framework.

Findings

The OEB has consistently applied stretch factors to total costs in order to incent productivity in both the areas of capital expenditure and OM&A. The OEB finds no compelling reason to depart from this approach. While the Application put forward by Toronto Hydro may be a custom application, one of the key aspects of the OEB's RRFE is the requirement to continue to make productivity improvements. As discussed later in this Decision, the OEB is concerned that the Application does not contain enough productivity incentives. Application of the stretch factor to the C factor is one way to remedy this deficiency.

The Use of Benchmarking

SEC argued that custom benchmarking is a critical aspect of a Custom IR application and that any distributor seeking greater increases in revenue requirement or rate than the norm should be in a position to file benchmarking evidence consistent with those greater levels. If they cannot, their additional spending requirements cannot be supported.

- the Board's inflation and productivity analyses; and
- benchmarking to assess the reasonableness of distributor forecasts.

Expected inflation and productivity gains will be built into the rate adjustment over the term.

Capital Spending

There will not be an ICM in the Custom IR method. Under this method, distributors will be expected to operate under their Board-determined multi-year rates.

Under Custom IR, planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle. This is consistent with the Board's existing policies in relation to incremental capital under 3rd Generation IR.

Annual IR Index

The Annual IR Index will be appropriate for distributors with primarily sustainment investment needs. The Annual IR Index is intended to provide a rate-setting approach that is simpler and more streamlined than the other two. Among other things, there is no forecast cost of service review under this method. Rates are adjusted by a simple price cap index formula. Initial rates are set by applying this adjustment to existing rates. The annual rate adjustments are designed to reflect "steady-state mode" operations – that is, rate adjustments will be comparatively minor.

Chart 12: Annual Nuclear Performance Measures

Nuclear Performance Measures

(Separate measures will be filed for Darlington and Pickering Stations)

Category	Measure
Safety	All Injury Rate (per 200k hours)
	Collective Radiation Exposure (person rem/unit)
	Airborne Tritium Emissions (curies)
	Industrial Safety Accident Rate (#/200k hours)
	Fuel Reliability Index (microcuries /gram)
	2-year Reactor Trip Rate (#/7000 hours)
	3-year Auxiliary Feedwater System Unavailability (#)
	3-year Emergency AC Power Unavailability (#)
	3-year High Pressure Safety Injection Unavailability
Reliability	Forced Loss Rate (%)
	Unit Capability Factor (%)
	Nuclear Performance Index (%)
	On-line Deficient Maintenance Backlog (work orders / unit)
	On-line Corrective Maintenance Backlog (work orders / unit)
	Chemistry Performance Indicator Annual YTD (#)
Cost Effectiveness	Total Generating Cost per Net MWh ($/MWh)
	Non-Fuel Operating Cost per Net MWh ($/MWh)
	Fuel Cost per Net MWh ($/MWh)
	Capital Cost per MW Design Electrical Rating ($k/MW)
Human Resources	18-month Human Performance Error Rate (#/10k ISAR hours)

Benchmarking Results – Plant Level Summary

Table 2 provides a summary of OPG Nuclear's performance compared to benchmark results.

Table 2: Plant Level Performance Summary

		2014 Actuals			
Metric	**NPI Max**	**Best Quartile**	**Median**	**Pickering**	**Darlington**
Safety					
All Injury Rate (#/200k hours worked)		0.66	N/A[1]	0.22	0.31
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.02	0.03	0.06
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	80.00	42.25	61.60	82.24	69.06
Airborne Tritium Emissions (Curies) per Unit[3]		1,014	2,410	2,390	1,831 ⇩
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000001	0.001580 ⇩	0.000158 ⇧
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.05	0.36	0.00
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0015	0.0181	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0001	0.0024	0.0000	0.0000
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.00000	0.00003	0.0000	0.0000
Reliability					
WANO NPI (Index)		92.9	85.8	64.3	92.1 ⇩
Rolling Average[2] Forced Loss Rate (%)	1.00	1.03	1.29	10.08	2.85
Rolling Average[2] Unit Capability Factor (%)	92.0	89.44	86.49	74.50	89.41
Rolling Average[2] Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.04 ⇧	1.00
1-Year On-line Deficient Maintenance Backlog (work orders per unit)		159	212	276 ⇩	176 ⇩
1-Year On-line Corrective Maintenance Backlog (work orders per unit)		11	20	160	20 ⇧
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)		38.71	44.61	67.93	37.73
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)		22.68	25.83	56.94	28.55
3-Year Fuel Cost per MWh ($ per Net MWh)		8.08	8.79	5.74	5.13
3-Year Capital Cost per MW DER (k$ per MW)		49.08	63.95	34.20	31.30
Human Performance					
18-Month Human Performance Error Rate (# per 10k ISAR and contractor hours)		0.00200	0.00400	0.00890	0.00620

Notes
1. No median benchmark available.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2012 data is used because 2013 and 2014 results were unavailable at the time of benchmarking.

Green = maximum NPI results achieved or best quartile performance

White = 2nd quartile performance

Yellow = 3rd quartile performance

Red = 4th quartile performance

⇩ Declining Benchmark Quartile Performance vs. 2013

⇧ Improving Benchmark Quartile Performance vs. 2013

Filed: 2017-02-10
EB-2016-0152
Exhibit L, Tab 6.2
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Attachment 3
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Benchmarking Results – Plant Level Summary

Table 2 provides a summary of OPG Nuclear's performance compared to benchmark results.

Table 2: Plant Level Performance Summary

Metric	NPI Max	2015 Actuals: Best Quartile	Median	Pickering	Darlington
Safety					
All Injury Rate (#/200k hours worked)		0.69	N/A[1]	0.44	0.22
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.00	0.05	0.08
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	80.00	38.17	48.53	97.72	79.55
Airborne Tritium Emissions (Curies) per Unit[3]		1,192	1,784	2,409 ⇩	1,313
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000001	0.000421 ⇧	0.000122
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.06	0.17	0.13
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0050	0.0115	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0006	0.0041	0.0030	0.0000
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0000	0.0000	0.0000	0.0000
Reliability					
WANO NPI (Index)		93.5	89.4	68.5	83.7 ⇩
Rolling Average[2] Forced Loss Rate (%)	1.00	0.38	1.46	6.85	3.65
Rolling Average[2] Unit Capability Factor (%)	92.00	91.31	88.05	77.32	83.96 ⇩
Rolling Average[2] Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.06 ⇩	1.00
1-Year On-line Deficient Maintenance Backlog (work orders per unit)		116	160	251 ⇩	174 ⇩
1-Year On-line Corrective Maintenance Backlog (work orders per unit)		7	15	125	24 ⇩
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)		38.93	44.38	67.36	44.38 ⇩
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)		22.60	25.89	56.49	33.19 ⇩
3-Year Fuel Cost per MWh ($ per Net MWh)		7.97	8.73	5.71	5.18
3-Year Capital Cost per MW DER (k$ per MW)		47.33	63.63	33.86	43.52
Human Performance					
18-Month Human Performance Error Rate (# per 10k ISAR and contractor hours)		0.0010	0.0030	0.0055 ⇧	0.0031

Notes
1. No median benchmark available.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2014 Industry data is used because 2015 results were unavailable at the time of benchmarking.

Green = maximum NPI results achieved or best quartile performance
White = 2nd quartile performance
Yellow = 3rd quartile performance
Red = 4th quartile performance

⇩ Declining Benchmark Quartile Performance vs. 2014
⇧ Improving Benchmark Quartile Performance vs. 2014

Total Generating Cost* ($/MWh)	Forecast 2016	Business Plan 2017	2018	2019	Projection 2020	2021
Enterprise	[redacted]					
Nuclear	63.2	75.6	74.6	74.5	77.1	77.3
Hydroelectric	[redacted]					

* Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

The business plan builds on efficiencies achieved to date, with a focus on pursuing further opportunities for cost effectiveness improvement across the generating business units and support services. In 2016, OPG adopted Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness, in addition to TGC per MWh metrics for each of the Nuclear and Hydroelectric operations. Enterprise-wide targets for TGC per MWh range from approximately [redacted] over the 2017-2021 period. The [redacted] in the TGC over the planning period reflects [redacted] the Darlington refurbishment outages, as well as [redacted] large hydroelectric project [redacted] the Sir Adam Beck I GS power canal liner rehabilitation. The TGC targets are adjusted for hydroelectric generation losses due to surplus baseload generation conditions.

A prominent feature of the OEB's incentive regulation framework is to encourage productivity savings. In particular, for the hydroelectric business, OPG's application requests regulated rates that reflect annual increases of less than inflation. For the nuclear business, OPG's application includes a stretch factor that reduces recoverable OM&A expenses below planned levels. This will challenge OPG to find additional cost savings within its operations, beyond those already reflected in planned cost levels. In order to improve profitability, OPG must identify and implement such additional efficiency improvements starting as early as 2017, with cost savings growing over time.

Benchmarking studies have indicated that OPG has reduced the gap to the average nuclear staffing benchmark from 17% in 2011 to 4% in 2014. With further sustained headcount reductions since 2014, OPG is confident that its current and planned nuclear staffing levels are at the benchmark level. OPG also benchmarks the costs of the Pickering and Darlington stations against other nuclear stations. On a per unit, basis, OPG's all-in operating and capital expenditures for the stations continue to be amongst the lowest in the industry. OPG's nuclear stations will continue to target strong reliability performance, including a top-quartile forced loss rate performance of 1.0% for the Darlington station and a 5.0% forced loss rate for the Pickering station consistent with planned investment levels, for the 2017-2019 period. The operational targets and associated initiatives for the Nuclear business unit are found in Appendix 4, with OPG's Nuclear strategic planning framework included in Appendix 5.

The hydroelectric stations continue to exhibit strong cost effectiveness performance, with regulated fleet operating costs, excluding Gross Revenue Charge (GRC) payable to the Province, benchmarking in the second quartile relative to peers. Operating targets for 2017-2019 include strong fleet-wide hydroelectric availability factors averaging [redacted] per year. The operational targets and associated initiatives for the Renewable Generation & Power Marketing (RG&PM) business unit are found in Appendix 6.

The operational targets and associated initiatives for OPG's centre-led Business and Administrative Services organization, which is focused on providing cost effective information technology, supply chain and real estate services in support of business priorities, are found in Appendix 7.

Production

Total planned OPG production ranges from [redacted] per year over the 2017-2019 period, [redacted] forecast in 2016 and [redacted] in 2021. This reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016, including a partial overlap starting in 2021 between the second and third unit refurbishments.

The following other main factors affect the variability in the planned nuclear production over the period:

- Incremental planned outage days at the Pickering station to enable continued operations in line with the business case approved by the Board in November 2015;
- Single Fuel Channel Replacement outage work at the Pickering station in 2019 and at the Darlington station in 2017 and 2020;

The TGC/MWh for Darlington has been calculated on a normalized and non-normalized basis for 2017 and 2018 to account for the impact of reduced unit output during Darlington Refurbishment. The denominator in TGC/MWh, i.e., MWh, declines because units are being refurbished but there is not a corresponding decline in the numerator, as corporate allocated costs and station costs are largely fixed. The net impact will be to temporarily skew these metrics higher than would otherwise be the case. Nuclear Operations has set internal performance targets for TGC/MWh on a non-normalized basis, but for benchmarking against industry peers, will continue to compare Darlington's performance using a normalized TGC metric.

The following summarizes the targets set for each of the four cornerstones for the period 2016-2018, specifically:

- For the safety cornerstone, OPG is targeting either best quartile performance or maximum NPI points at both stations with a focus on improving Collective Radiation Exposure at Pickering and the Fuel Reliability Index at Darlington.
- For the realiablity cornerstone, OPG is targeting best quartile (1.0 per cent) at Darlington over the test period despite an actual FLR of 4.86 per cent in 2015. Darlington's UCF is targeted to improve (UCF exludes impact of unit outages for DRP). OPG is targeting a FLR of 5.0 per cent at Pickering across the test period which compares favourably to an average FLR of 8.5 per cent over the period 2010-2015 (See Ex. E2-1-1 section 3.1.2). OPG is targeting a lower FLR at Pickering based on past and expected future improvements in equipment reliability. Improvements are also targeted at both Pickering and Darlington to reduce Online Deficient and Corrective Maintenance backlogs. Pickering's UCF is targeted to be lower, reflecting the extensive additional planned outage days for Pickering Extended Operations.
- For the value for money cornerstone, OPG is targeting an increase in the normalized TGC/MWh for Darlington in 2016 and 2017 before slight decline in 2018. This is driven by expectation of a minimal increase in operating costs primarily reflecting labour escalation and higher capital investment. OPG is also targeting an increase in Pickering's TGC/MWh over the 2016-2018 planning period primarily due to lower

MWh associated with extensive additional planned outages for Pickering Extended Operations.

- For the human performance cornerstone, OPG is targeting improvement at Darlington, as indicated in the target reductions in the HPER over the 2016-2018 planning period. Pickering HPER is targeted to remain unchanged over this period.

Projected targets for the three key metrics of TGC/MWh, FLR and UCF for 2019-2021 are provided in Chart 5. These are challenging targets, which will require OPG to establish new initiatives based on future outcomes and operating conditions in order to achieve them.

Chart 5

Projected Targets for Key Metrics

Benchmarking Indicators	Pickering – Annual Targets			Darlington – Annual Targets		
	2019	2020	2021	2019	2020	2021
Safety						
Forced Loss Rate (%)	5.0	5.0	5.0	1.0	4.2	3.0
Unit Capability Factor (%)	72.6	73.4	70.6	87.8	79.4	90.9
Normalized Total Generating Cost per MWh ($/Net MWh)*	N/A	N/A	N/A	51.68	52.04	39.80
Total Generating Cost per MWh ($/Net MWh)*	78.36	74.93	81.16	64.61	73.82	64.90

* TGC/MWh and Non-Fuel Operating Cost per MWh exclude centrally held pension and OPEB costs and asset service fees to align with the industry standard.

Darlington's FLR in 2020 and 2021 is impacted by the assumed FLR for refurbished Unit 2 returning to service and is consistent with the assumptions that underpin the Darlington Refurbishment Execution Phase Business Case (Ex. D2-2-8 Attachment 1). The decline in Darlilngton's TGC/MWh in 2021 is largely explained by the expectation that two units will be subject to refurbishment in 2021. As a result there will be signficantly lower outage OM&A as there are no planned outages with the excepton of a short post refurbishment outage as described in Ex. E2-1-1.

4.2. Annual Performance Reporting Process

OPG proposes an annual written process for reporting on the prior year's performance and identifying targets for the following year. Beginning in 2017, OPG would file an updated set of performance measures with the OEB annually. The updated measures would include the prior year's actual performance as well as targets for the new year for each measure.

OPG believes that these measures will give the OEB and interested parties a clear and meaningful view into the company's operation during the 2017-2021 period. As is the case for electricity distributors, OPG proposes that no rewards or penalties be attached to the company's performance. In OPG's view, annual reporting exists to give the OEB and stakeholders a clear view of OPG's performance during the longer term of this application. The OEB will be able to understand whether OPG is meeting operational targets and financial expectations.

5. CUSTOMER ENGAGEMENT

5.1. Overview

This section reviews the various ways in which OPG engages with the individuals, businesses and institutions that consume electricity in Ontario and considers customers when planning work and operating its generating facilities. This schedule also describes OPG's ongoing plans to expand the formal role of customer outreach in the company's business planning process.

The RRFE requires that electricity distributors work to provide services in a manner that responds to identified customer preferences. OPG does not have a direct relationship with electricity consumers, since it sells electricity wholesale into the IESO-controlled market. As a result, OPG does not perform the transactional customer activities that a distributor does. OPG does not manage customer accounts, respond to service calls, or make investment

Board Staff Interrogatory #103

Issue Number: 6.2
Issue: Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

Interrogatory

Reference:
Ref: Exh A2-2-1 Attachment 1 page 30
The nuclear business operational performance and targets are summarized in a table at page 30 of the OPG 2016-2018 business plan.

a) Are the 2015 actual operational performance data annual results or rolling actual results? If the data are annual results, please provide the rolling results.

b) Note 1 to the table states that the Darlington targets reflect the impact of the Unit 2 refurbishment. Please identify the Darlington targets and explain how the Unit 2 refurbishment is reflected in these targets.

Response

(a) All eight of the 2015 actual operational performance data set out in Ex. A2-1-1, Attachment 1, p. 30, with the exception of WANO NPI (rolling average) and Human Performance Error Rate (18 months), are annual results. OPG calculates the following five metrics on a rolling average basis (two-year rolling for Pickering; three-year rolling for Darlington), as set out in Chart 1 below:

Chart 1: Operational Performance Data – 2015 Rolling Average

Metric	Pickering	Darlington
Collective Radiation Exposure (person-rem/unit)	97.72	79.55
Unit Capability Factor (%)	77.3	84.0
Forced Loss Rate (%)	6.85	3.65
WANO NPI (Index)	68.5	83.7
Total Generating Cost per MWh	67.36	44.38

(b) The Darlington performance targets shown at Ex. A2-2-1, Attachment 1, p. 30 were established to apply to the three operating units (Units 1, 3, and 4) as well as any impact from operation of systems common to the operating units (Unit 0). The targets were derived to exclude any impact from the Darlington Unit 2 refurbishment. For example, the unit capability factor (%) reflects expected generation of the three operating units, and excludes the lost generation foregone during the Unit 2 refurbishment outage.

The exception is Total Generating Cost per MWh, which has both a normalized and non-normalized target. Nuclear Operations has set internal performance targets for TGC/MWh on a non-normalized basis (Ex. F2-1-1, p. 16), which excludes any impact from Darlington Unit 2 Refurbishment. By comparison, the normalized target has been adjusted to show normalized costs per MWh for Darlington as outlined in Ex. F2-1-1, p. 16 and described further at L-6.2-1 Staff-101.

2021, which is the sum of the deferred revenue requirement amounts for those years shown in Chart 4.

Chart 4

OPG Proposed Deferred Nuclear Revenue Requirement[17]

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,202	$ 3,223	$ 3,310	$ 3,824	$ 3,438
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Smoothed Rate ($/MWh)	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
Smoothed Revenue ($M)	$ 2,507	$ 2,810	$ 3,165	$ 3,362	$ 3,535
Deferred Revenue Requirement ($M)	$ 694	$ 412	$ 145	$ 462	$ (97)

3.0 MID-TERM PRODUCTION REVIEW

OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to July 1, 2019) for:

1) an update of the nuclear production forecast and consequential updates to nuclear fuel costs underpinning the payment amounts for the final two-and-a-half years of the five-year application period (July 1, 2019 to December 31, 2021); and
2) disposal of applicable audited deferral and variance account balances (most accounts would reflect amounts accumulated over the period January 1, 2016 to December 31, 2018) as well as any remaining unamortized portions of previously approved amounts with recovery period extending beyond December 31, 2018.

3.1 Rationale for Mid-Term Review

In this application, OPG has provided a nuclear production forecast that covers the full five-year period from January 1, 2017 to December 31, 2021. The company's nuclear production forecast and forecasting process are described in detail in Ex. E2-1-1. The production forecast is based on a set of current assumptions that are challenging to meet, with the risk of

[17] Proposed Revenue Requirement per Ex I-1-1 Table 2
Forecast Production per Ex E-2-1 Table 1
Smoothed Rate determined by escalating the existing $59.29 approved nuclear payment amount from EB-2013-0321 by 11% each year
Smoothed Revenue determined by applying the Smoothed Rate to the Forecast Production
Deferred Revenue calculated as the difference between the Proposed Revenue Requirement and the Smoothed Revenue

deviations from forecast increasing into the second half of the application. OPG's mid-term review application will include the revised production forecast underpinning its latest approved business plan for the period July 1, 2019 to December 31, 2021 (the "mid-term production forecast"). The mechanics of the mid-term review proposal are discussed in section 3.2.

Substantial uncertainty exists relating to events that could result in substantial impacts on OPG's production in the latter half of OPG's five-year application. Circumstances could result in substantially higher or lower production than currently forecast. If production is higher than forecast, customer bills would be unnecessarily inflated (i.e., the higher production would result in a credit balance in the proposed Mid-term Nuclear Production Variance Account, to be refunded to customers in the next payment amount application). If production is lower than forecast, OPG may not recover its revenue requirement. Mitigating this risk benefits both customers and the company.

OPG expects that the nuclear production forecast that will be included in its future approved business plans will reflect an increased level of certainty related to events that may affect production during the second half of the test period, providing a sufficiently robust basis for setting reasonable production performance targets for the second half of the test period that would be fair to both customers and OPG.

As discussed during consultation with stakeholders, several factors make it extremely difficult to accurately forecast OPG's annual nuclear production over the five-year period covered by this application:

i. Public Policy Changes: Changes to public policy, especially the Government of Ontario's Long Term Energy Plan ("LTEP") could impact OPG's nuclear production. In particular, a change to the refurbishment schedule for future units at the Darlington generating station could materially alter OPG's production schedule within the period of this Application.
ii. Pickering Extended Operations: Canadian Nuclear Safety Commission ("CNSC") approval is still required and, as discussed in Ex. F2-2-3, OPG has not yet completed

work necessary to confirm that the Pickering units would be fit to operate beyond 2020.

iii. Execution of Darlington Refurbishment Program: If refurbishment of the first unit at Darlington is completed earlier or later than scheduled, production may vary. In addition, there is a risk that the post-refurbishment forced loss rate at Darlington may vary from OPG's current forecast. These factors have the potential to materially decrease or increase production, depending on the circumstances.

iv. Regulatory Requirements and Approvals: OPG's nuclear facilities are subject to significant regulatory oversight. Changing requirements and work required to comply with existing requirements have the potential to affect OPG's nuclear production forecast.

v. Aging Facilities: The risk of unplanned outages increases as units begin to approach their end of life, in particular for Pickering given on-going work on asset condition assessment and fuel channel work and pending CNSC licence renewals.

OPG expects that it will be better able to assess these and other risks, and their potential effect on production, at the time of the proposed mid-term review.

The mid-term review of nuclear production is also consistent with the rate-smoothing requirements in O. Reg. 53/05 and would protect both customers and OPG. The regulation requires the OEB to determine revenue requirements for the nuclear facilities for each year on a five-year basis, and to determine the portion of the approved revenue requirement to be recorded in the RSDA.[18] Subject to the OEB concluding that rates are no longer just and reasonable pursuant to Section 78.1 of the Act, the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years. However, while the revenue requirement must be determined on a five-year basis, no such limitation exists for the determination of production.

The production forecast is a critical element of OPG's rate-setting framework given OPG's rate structure. As noted in Ex. E2-1-1, there are a number of factors that could materially

[18] O. Reg. 53/05, sub-paragraphs 6(2)12 (i) and (ii).

impact OPG's production which are too uncertain to predict with reasonable precision. Given the relatively long term of this application and the uncertainty of nuclear production during that period, a mid-term review of nuclear production and related fuel costs for the second half of the application term (i.e., July 1, 2019 to December 31, 2021) would help address the forecast uncertainty inherent in OPG's production forecast as it looks further into the future and provides a basis to set reasonable production performance targets for the second half of the application term.

In general, it is more difficult to forecast events further in the future. This difficulty increases further when the subject matter of the forecast is inherently uncertain. Since the inception of regulation by the OEB, there have been a number of variances between OEB approved and actual production. It has proven difficult to forecast nuclear production in the past where OPG's Pickering and Darlington facilities were operating in a comparatively steady state compared to the operating circumstances that will be facing these facilities during the application period. Even with a mid-term review, the proposed ratemaking methodology will result in a significant increase in production forecast risk compared to previous applications.[19]

As discussed in Ex. A1-3-2, a completely variable rate provides a strong financial incentive to OPG to achieve or surpass the OEB approved production forecast, thereby increasing the quality of service (e.g., increased availability, reduced EFOR) provided to customers. The approved production forecast is effectively a performance target with financial rewards and penalties.

3.2 Mechanics of Mid-Term Production Review

OPG proposes to file an application to review the company's updated nuclear production forecast and associated fuel costs in the first quarter of 2019. The scope of this application would be limited to a review of OPG's nuclear production forecast for the period from July 1, 2019 to December 31, 2021, any consequential revisions to forecast fuel costs, and the disposition of audited December 31, 2018 balances in deferral and variance accounts

[19] In previous applications, OPG's payment amounts have been based on forecast production of two years or less.

generation losses[1] during the test period reflect challenging targets. While any production forecast is subject to unplanned outcomes, OPG continues to be subject to unanticipated production disruptions due to events such as an unbudgeted planned outage in 2015 to replace PHT pump motors at Darlington. Smaller (albeit negative) production variances were achieved in 2014 and 2015 when compared to previous years, as shown on Chart 2.

Chart 2

OPG Nuclear Production Variance and Revenue Impact

Line No.		2008	2009	2010	2011	2012	2013	2014	2015	Average	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**OPG Application - TWh**	**51.4**	**49.9**	**-**	**48.9**	**50.0**	**-**	**48.5**	**46.1**		
2	**OEB Approved - TWh+**	**51.4**	**49.9**	**50.7**	**50.4**	**51.5**	**51.0**	**49.0**	**46.6**		
3	**Actual -TWh**	**48.2**	**46.8**	**45.8**	**48.6**	**49.0**	**44.7**	**48.1**	**44.5**		
4	**Variance (TWh)** (line 3 - line 2)	**-3.2**	**-3.1**	**-4.9**	**-1.8**	**-2.5**	**-6.3**	**-0.9**	**-2.1**	**-3.2**	**-24.7**
5	**Revenue Impact - $M#**	**-159.9**	**-154.9**	**-242.4**	**-87.3**	**-121.3**	**-305.7**	**-45.9**	**-114.3**	**-154.0**	**-1231.8**

\+ 2010 is the average of 2008 and 2009 Board Approved; 2013 is average of 2011 and 2012 Board Approved.

\# At OEB-approved rates of $52.98/MWh for 2008-2010 less fuel cost, and $51.52/MWh for 2011-2013 less fuel cost.
For 2014, 10 months at OEB–approved rate of $51.52/MWh and 2 months at OEB approved rate of $59.29/MWh, less fuel cost (average $52.82/MWh).
For 2015, at OEB approved rate of $59.29/MWh less fuel cost

The test period production forecast takes into account the following:

- Darlington Refurbishment Program with Darlington Unit 2 being taken out of service in 2016, followed by Unit 3 in 2020, Unit 1 in 2021 (and Unit 4 in 2023). Each unit refurbishment project will take more than three years to complete. Two post-refurbishment mini-outages have been scheduled for Unit 2 to address equipment reliability issues that are expected to emerge post refurbishment. The need for these post-refurbishment outages is based on operating experience at other nuclear facilities that underwent major refurbishment. The first mini "warranty" outage of 55 days duration is scheduled for Unit 2 in 2020, within six months post refurbishment. The duration will allow sufficient time for anticipated equipment repair by the vendors. The second mini "warranty" outage of 31 days duration is scheduled for Unit 2 in 2021, within 18 months post-refurbishment. The shorter duration is due to an

[1] See Attachment 1 - Glossary of Outage and Generation Performance Term for definitions.

700 University Avenue Toronto, ON M5G 1X6
Tel: 416-592-4008 or 1-800-592-4008 Fax: 416-592-2178
www.opg.com

Jan. 11, 2016

OPG READY TO DELIVER REFURBISHMENT OF DARLINGTON NUCLEAR STATION
OPG also planning continued operation of Pickering Station

Toronto - Ontario Power Generation (OPG) is ready to deliver on the Government's decision to invest in refurbishing the first of four units at the Darlington Nuclear Generating Station. The Province has also approved plans to pursue continued operation of the Pickering Nuclear Generating Station to 2024.

"Refurbishing Darlington is an investment in Ontario -- in clean air, in jobs, in innovation, and in lower energy prices," said OPG President and CEO Jeffrey Lyash. "We've been preparing since 2009 and we're ready to deliver the job safely, on time and on budget."

The $12.8 billion investment will generate $14.9 billion in economic benefits to Ontario, which include thousands of construction jobs at Darlington and at some 60 Ontario companies supplying components for the job. This investment will also preserve about 3,000 jobs as it provides 30-plus years of clean, reliable, base load power, at a cost lower than other alternatives considered. The budget is about $1.2 billion less than originally projected by OPG, and all four units are scheduled for completion by 2026.

"OPG has already delivered the single largest action in North America to combat climate change by ending the use of coal to generate electricity," added Lyash. "Having a clean, reliable electricity system with predictable, stable prices is not just an environmental achievement, it's essential to the province's long-term competitiveness."

The price of power from the refurbished station is expected to be between seven and eight cents per kilowatt hour. The Ontario Energy Board (OEB) will determine the final rate.

The refurbishment project will be subject to strict oversight to ensure safety, reliable supply and value for customers. OPG has also implemented a robust risk management strategy to ensure contractors are held accountable and appropriate off-ramps are in place.

Also announced today, OPG will work with the Ministry of Energy, the Independent Electricity System Operator and the OEB to pursue continued operation of the Pickering Station to 2024. All six units would operate until 2022; two units would then shut down and four units would operate to 2024. Extending Pickering's operation would ensure a reliable, clean source of base load electricity during the Darlington and initial Bruce refurbishments.

"Our technical work shows that Pickering can be safely operated to 2024 and that doing so would save Ontario electricity customers up to $600 million, avoid eight million tonnes of greenhouse gas emissions and protect 4,500 jobs across Durham Region," said Lyash. "We'll work closely with our community partners as we go through this process."

Any plan to extend Pickering's life would require approval from the Canadian Nuclear Safety Commission (CNSC). OPG has started work on a licence application for CNSC approval in 2018.

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For further information, please contact:
Ontario Power Generation Media Relations
416-592-4008 or 1-877-592-4008
Follow us @opg

700 University Avenue Toronto, ON M5G 1X6

Tel: 416-592-4008 or 1-877-592-4008
www.opg.com

Jan. 11, 2016

DARLINGTON REFURBISHMENT
ENSURING SUCCESS, PROTECTING CUSTOMERS

OPG is well-positioned to deliver the Darlington Refurbishment on time and on budget. Darlington is one of the world's top performing nuclear stations. We've put in years of detailed planning, built a state-of-the-art training facility, assembled an excellent team, and partnered with top companies from across Ontario.

Years of Extensive Project Planning

- Detailed planning commenced in 2010 and concluded at the end of 2015;
- Lessons learned from other major projects have been incorporated;
- A state-of-the-art full-size reactor mock-up was built to test specialized tools and train workers;
- Engineering was completed before field execution starts;
- Site preparations focused on maximizing worker productivity;
- Scope, schedule and cost are developed to a level of detail not seen on prior projects;
- Co-operating closely with Bruce Power;
- Contracts structured so contractors are accountable for price and schedule to minimize risk to ratepayers.

Experienced Project Management Team

- OPG has a project management team with extensive refurbishment experience from Canada and around the world;
- Team members include those seconded to Atomic Energy of Canada Ltd. to work on the Pt. Lepreau refurbishment project in New Brunswick; OPG managers delivered the balance of the project on time and on budget;
- Continuing to acquire talent from other major projects to enhance the project management team and develop future leaders;
- We're also working with the best in the business via our contract partners.

Significant Oversight and Public Reporting

- OPG has direct oversight of all aspects of the project, plus two independent oversight organizations in place;
- One oversight group reports directly to the Project Executive and the OPG Board of Directors;
- One oversight group reports directly to the Ontario Ministry of Energy;

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From March 2, 2017 to the e-Laws currency date.

Last amendment: O. Reg. 57/17.

This Regulation is made in English only.

Definition

0.1 (1) In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"calculation period" means each period for which the Board determines the approved revenue requirements under subparagraph 12 ii of subsection 6 (2) together with the year immediately prior to that period;

"Darlington Refurbishment Project" means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Darlington Nuclear Generating Station;

"deferral period" means the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends;

"hydroelectric facilities" means the hydroelectric generation facilities prescribed in paragraphs 1, 2 and 6 of section 2;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"nuclear facilities" means the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement.

"OPG weighted average payment amount" for a year means the total production-weighted average payment amount that is used in the determination of the payments made under section 78.1 of the Act with respect to the generation facilities prescribed in section 2 of this Regulation, calculated according to the formula:

$$(((NPA + NPR) \times NPF) + (HPA + HPR) \times HPF) / (NPF + HPF)$$

where,

NPA is the Board-approved payment amount for the year in respect of the nuclear facilities,

NPR is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the nuclear facilities, excluding the deferral account established under subsection 5.5 (1),

NPF is the Board-approved production forecast for the nuclear facilities for the year,

HPA is the Board-approved payment amount for the year, or the expected payment amount resulting from a Board-approved rate-setting formula, as applicable, in respect of the hydroelectric facilities,

HPR is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the hydroelectric facilities, and

HPF is the Board-approved production forecast for the hydroelectric facilities for the year.

O. Reg. 23/07, s. 1; O. Reg. 353/15, s. 1; O. Reg. 57/17, s. 1.

(2) For the purposes of this Regulation, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 312/13. s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.
   ii. Sir Adam Beck II.
   iii. Sir Adam Beck Pump Generating Station.
   iv. De Cew Falls I.
   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station.
6. As of July 1, 2014, the generation facilities of Ontario Power Generation Inc. that are set out in the Schedule. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2; O. Reg. 312/13, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

4. REVOKED: O. Reg. 312/13, s. 3.

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled “Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05” posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

5.1 REVOKED: O. Reg. 312/13, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

5.3 REVOKED: O. Reg. 312/13, s. 3.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Darlington refurbishment rate smoothing deferral account

5.5 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the commencement of the deferral period, the difference between,

(a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and

(b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities. O. Reg. 353/15, s. 2.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account at a long-term debt rate reflecting Ontario Power Generation Inc.'s cost of long-term borrowing that is determined or approved by the Board from time to time, compounded annually. O. Reg. 353/15, s. 2.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,

   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and

   ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.

3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

i. capital cost allowances,

ii. the revenue requirement impact of accounting and tax policy decisions, and

iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

i. return on rate base,

ii. depreciation expense,

iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2.

11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

12. For the purposes of section 78.1 of the Act, in setting payment amounts for the nuclear facilities during the deferral period,

i. the Board shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period,

ii. the Board shall determine the approved revenue requirements referred to in subsection 5.5 (1) and the amount of the approved revenue requirements to be deferred under subparagraph i on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the Board determines,

iii. for greater certainty, the Board's determination of Ontario Power Generation Inc.'s approved revenue requirement for the nuclear facilities shall not be restricted by the yearly changes in payment amounts in subparagraph i,

iv. the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5.5 (1), and the Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period, and

v. the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3; O. Reg. 57/17, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

SCHEDULE

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.
9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.
13. Chats Falls.
14. Chenaux.
15. Coniston.
16. Crystal Falls.
17. Des Joachims.
18. Elliott Chute.
19. Eugenia Falls.

20. Frankford.
21. Hagues Reach.
22. Hanna Chute.
23. High Falls.
24. Indian Chute.
25. Kakabeka Falls.
26. Lakefield.
27. Lower Notch.
28. Manitou Falls.
29. Matabitchuan.
30. McVittie.
31. Merrickville.
32. Meyersberg.
33. Mountain Chute.
34. Nipissing.
35. Otter Rapid.
36. Otto Holden.
37. Pine Portage.
38. Ragged Rapids.
39. Ranney Falls.
40. Seymour.
41. Sidney.
42. Sills Island.
43. Silver Falls.
44. South Falls.
45. Stewartville.
46. Stinson.
47. Trethewey Falls.
48. Whitedog Falls.

O. Reg. 312/13, s. 5.

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Board Staff Interrogatory #259

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh H1-1-1, page 30, Exh A1-3-3, page 12

In its evidence, OPG describes the entries to be included in the Mid-term Nuclear Production Variance Account, as follows:

> To determine entries into the account, the monthly production variance will be multiplied by the approved smoothed nuclear payment amount. The resulting amount would then be reduced by an amount determined as a monthly production variance multiplied by the average fuel cost in the approved revenue requirement for the applicable year.

a) Please provide a sample calculation that would show the practical application of methodology outlined in Exh H1-1-1.

b) In Exh A, it's stated that "the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years". How is OPG's proposed adjustment to fuel cost in the Mid-term Nuclear Production Variance Account consistent with the preceding statement?

Response

a) A sample calculation for the year 2020 is provided in Chart 1 below, based on the following assumptions:

   1) The OEB approves a production forecast for July 1, 2019 to July 2021 that is 1 TWh less (the "Mid-term Production") for 2020 than OPG approved in the current application; and

   2) The OEB approves OPG's proposal in the current application, in particular:
      a. that nuclear payment amounts increase at a constant rate of 11% per year in the IR Term, and
      b. the Nuclear production forecast and fuel cost for all years in the IR Term.

The relevant values for 2020 are reflected in Chart 1:

Chart 1 – Sample Calculation

Line	Description	Amount	Evidence Reference
1	Smoothed Rate ($/MWh)	90.01	Ex. A1-3-3, p. 10, Chart 4, line 3
2	Fuel Cost ($M)	223.6	Ex. F2-5-1 Table 1 (line7 – line 6)
3	Production (TWh)	37.36	Ex. A1-3-3, p. 10, Chart 4, line 2
4	Average Fuel Cost ($/MWh)	5.985	Chart (line 2 / line 3)

The approach is described in Ex. A1-3-3, p. 14, lines 6-12. The annual production variance (i.e., 1TWh) will be multiplied by the net of the approved smoothed nuclear payment amount (i.e., $90.01/MWh) and the average fuel cost in the approved revenue requirement ($5.985/MWh) for the applicable year. The amounts determined above (i.e., 1TWh x ($90.01/MWh - $5.985/MWh) = $84.025M) will be recorded in the proposed Mid-Term Nuclear Production Variance Account described in Ex. H1-1-1. The related accounting entries would be:

Mid-Term Nuclear Production Variance Account	$84.0325M	(Debit)
Fuel Expense	$5.985M	(Debit)
Revenues	$90.01M	(Credit)

b) Unlike other costs, Nuclear fuel is a direct marginal cost associated with production. OPG believes it is appropriate that fuel cost be revised to correspond with any update to the Nuclear production forecast as part of the mid-term review. Any approved changes in nuclear fuel cost would be recorded in the Mid-term Nuclear Production Variance Account and would not involve re-opening the approved nuclear revenue requirement.

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility’s ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

- Benchmarking: Benchmarking is a fundamental requirement of a Custom IR application, both internal benchmarking to demonstrate continuous improvement and external benchmarking as identified in Section 5. A Custom IR application without benchmarking will be considered incomplete.

- Performance Metrics: The OEB has established a scorecard for electricity distributors, however, additional performance metrics should also be proposed so that expected outcomes can be monitored. All other utilities must propose a comprehensive scorecard that is informed by the scorecard for electricity distributors, but specifically includes other performance metrics aligned to the outcomes identified in the application. This is required for both Custom IR and cost of service rate applications.

- Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to that method for the duration of the approved term and will not seek early termination or in-term updates except under exceptional circumstances and with compelling rationale.

A Custom IR application can include a five year forecast of all costs with proposed rates for each year that consider both these costs and the proposed productivity improvements reflected in the custom index. A utility that cannot forecast its needs within the five year term, or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances.

The ICM and ACM mechanisms for funding capital for electricity distributors, or any similar mechanism approved for transmitters, natural gas distributors or OPG, are not available for utilities setting rates under Custom IR.

An acceptable adjustment during a Custom IR term is a Z factor mechanism for cost recovery of unforeseen events. The OEB has a policy for Z factors for electricity distributors and transmitters that applies for any rate-setting option chosen by a utility. The OEB has established a materiality threshold for electricity distributors for eligibility to claim for a Z factor event. Electricity transmitters are expected to propose a materiality threshold in their applications. The OEB has approved Z factor mechanisms for natural gas distributors in previous proceedings, and they may propose mechanisms in their future rate applications.

Given the custom nature of a Custom IR application, utilities may propose alternative mechanisms for unforeseen events to coordinate better with other aspects of their custom proposals. In doing so they should consider the OEB's expectations for protecting customers from excess earnings, as discussed in the next section.

- Protecting Customers: A key objective of incentive regulation is to drive productivity improvements within the utilities. The OEB has determined that with the Custom IR rate setting option, customers will benefit from the expected productivity improvements during the term through the custom index.

  Utilities that achieve productivity improvements above what is expected are allowed to keep certain earnings above the approved ROE. However, the OEB expects utilities filing a Custom IR application to propose one or more mechanisms to protect customers from utility earnings that become excessive. Proposals would typically include mechanisms such as off ramps (discussed